LSWG Evaluation Framework for  
Critical Consumption Product

DRAFT

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The load shift working group is developing a series of possible “products” for DR Load Shift – market integrated or market informed programs, and other strategies. This evaluation framework is intended to provide a consistent basis for comparing these options and judging the merits of the products under the following guidance from the CPUC:

* The product is market integrated;
* The product is not a rate; and
* The product is not directly related to DR serving distribution deferral service.

The framework includes three sections. These sections would be filled out for each product.

* **Background:** Backgroundthat describes the attributes described in the product description and evaluation sections.
* **Product description** **section:** A standard framework for describing the details of the product. Since the working group is including speculative and preliminary products in the discussion, some of these details may be limited or include a few options or a range. In some cases when there is a similar product, there will be a description of how that product works today and how they would need to change for a load shift product.
* **Product evaluation section:** Based on the product description, a synthesis of how the product is expected to benefit the grid and be implemented by customers, market participants, and the operators of the power system.

*Note: The format of this framework document is to describe each element, and to include an intended [answer type] in square brackets. These answer type formats are not intended to be rigid, but a possible format to help with comparison.*

*In terms of how to define a “product”, it may be appropriate to include a range or set of options in cases where more than one answer is possible. It may also be appropriate to create a separate product for consideration when the difference in options significantly changes the evaluation.*

# Product Description

The goal of this section is to clearly and concisely describe the product concept.

**Product Name: Critical Consumption Product** (to be piloted in a Critical Consumption Period Pilot)

**Short Description:**

The Critical Consumption Product is a load increase demand response product that can be considered to be integrated into the wholesale market because it is informed by the market. The incremental load increase is triggered directly by negative wholesale Day Ahead nodal market prices and paid at the real time nodal wholesale market prices (i.e., an average of real-time intervals in a 15-minute retail interval). The increases in solar (and to a lesser extent wind) generation correspond to negative or low wholesale electricity prices.[[1]](#footnote-1) The load increase product could possibly be paired with a load drop and thus be a load shift product, depending on notification times and stakeholder willingness to support this approach. However, there would not be an exact 1:1 load shift requirement.

The load increase (Critical Consumption) would occur during Critical Consumption Periods, which are intended to occur during periods of renewables curtailment due to low net load (as represented by the belly of the duck in the infamous CAISO duck curve). Renewables curtailment has increased from 187 GWh in 2015, to 308 GWh in 2016, to over 404 GWh in 2017.[[2]](#footnote-2) The load increase would be incented by having the incremental load “pay” a negative real-time wholesale market nodal price for energy (and non-energy components of the retail rate), and \*possibly\* earn a monthly participation incentive. There is a link between negative day-ahead prices and likelihood of curtailment of renewable resources in real time. This proposal seeks to (1) raise the belly of the duck and avoid renewable curtailment, and (2) enable California’s large, energy intensive power customers to take advantage of their investment in renewable resources by accessing excess, low-cost renewable energy to power manufacturing and industry. Both of these would help the state meet GHG emissions reductions goals. It would also address the current gap in DR Programs due to the termination of the Demand Bidding Program.

Previously, customers were able to dual participate in the Base Interruptible Program (a capacity program) and the Demand Bidding Program (an energy program), but the Demand Bidding Program was terminated at the end of 2016 for PG&E and the end of 2017 for SCE. No replacement energy program has been offered since that would enable customers to continue dual participation in an energy program and BIP. This resulted in a gap in DR Programs. Since the Critical Consumption Period is an energy program, it should enable industrial customers to dual participate in both reliability (the Base Interruptible Program for capacity) and economic energy (Critical Consumption Period Pilot) demand response, per dual participation rules. The question has been raised whether the current dual participation rules should apply to demand response that increases load. The goal of dual participation rules is to avoid double payment for the same change in load. Here, several of the same safeguards that avoided double payment for dual participation BIP and DBP apply: one is capacity and the other is energy; one is day of and the other is day ahead; if, in the unlikely event the events overlap, the BIP event would take priority, with no payment for the CCP event. Moreover, here, the BIP change in load is a reduction and the CCP change in load is an increase; CLECA believes that the goal of the dual participation rules, to avoid double payment, would be met. This question, however, may need to be explored further, to ensure all stakeholder and staff questions are answered and to eliminate double payment concerns.

**Dispatch method:** How are loads dispatched or instructed to shift?

* **Triggers:** Load is instructed to shift by an IOU/LSE communication based on the actual Day Ahead market run. When the actual Day Ahead market price is negative, a Critical Consumption Period may be triggered.
  + Based on prior years, it is expected (although not guaranteed) that most Critical Consumption Periods of negative pricing will occur during the Spring months, and are more likely on weekend days; 2017 CAISO Real time 15 minute pricing data on periods of low or negative prices suggest there could be more than 12-15 events, but there have been fewer periods of negative pricing so far in 2018.
  + While there have been fewer periods of negative pricing, CAISO data shows that renewable curtailment has continued, both at the local and system level.[[3]](#footnote-3)
* **Duration:** The Critical Consumption Period can have varying durations, from 1 to 6 hours, with the customer able to select the duration range.
* **Quantity:** The customers’ Critical Consumption (the increased consumption amount) based upon different prices would be nominated on a monthly basis, and the customer may opt to have different Critical Consumption amounts for weekends vs. weekday amounts. When the IOU/LSE communicates an event, the customer can opt to participate in the event with an increased consumption amount.
* What is the time and spatial granularity?
  + Time step of dispatch signal day-ahead nodal price is the dispatch signal;

in the real-time market, customers are exposed to Real Time 15-minute pricing increments; customer to select their event duration range, with the actual event duration set by the market, in 1-hour increments

* + Advance notice time to customer day ahead, by 5 pm at the latest
  + Scale of geographic detail nodal
  + Expected frequency of dispatch No limit; available year-round, but most CCPs

are expected to occur in the winter and spring seasons (shoulder months); CLECA suggests a minimum range of 12-15 Critical Consumption Periods over the course of the year; this range could be increased by the LSE; participation is voluntary and there is no penalty for not performing. If a customer cannot respond with a load increase during an event, the event performance would be the same as the baseline (effectively an opt-out, but it would not have to be tracked by the administrator). In the unlikely circumstance of a Critical Consumption Period simultaneous with a DR Reliability Program (ie BIP) call, the reliability event would take priority and the CCP event will not count toward the minimum number of events.

* What is the triggering signal? Negative Day Ahead

Market price as indicative of likely renewable

curtailment

* Is signal modified before dispatch? No

**Organizational roles:**

*Describe responsibilities, relationship, and payments between the following parties (or N/A):*

Customer Customer provides the energy product and

“pays” the wholesale energy price for the incremental Critical Consumption during

the Critical Consumption Period

Third Party / Aggregator Could aggregate customers to participate in

the utility/LSE program

Load Serving Entity (CCA or IOU or DA provider) runs or participates in an IOU pilot program, communicates the triggered events and passes through the savings from the wholesale market

Distribution utility / service territory LSE (IOU) runs the pilot program and settles the activities similar to PG&E’s XSP settlements, may rely on an administrator (eg, Olivine, as in XSP), paying the customer for participation

CAISO No specific role, other than timely closing of DA market run with market run results announced by 2 pm[[4]](#footnote-4)

Jurisdiction roles Pilot would be CPUC-jurisdictional and

administered by CPUC-jurisdictional entities and overseen by the CPUC, as with other CPUC-jurisdictional DR Pilots (e.g., DRAM, SSP, XSP)

**Participating load / device boundary and settlement**

*This set of criteria clarifies the options for participation by devices and/or premises-level load.*

Is the product technology neutral? yes

What is the smallest intended boundary for settlement? Premises; could be an aggregation

Sub-metering needs / value? no

What is the settlement process (i.e., how is value estimated and performance verified)?

* Aggregator role if participating, authorize MDMA to

provide meter data

and baseline calculations to Scheduling Coordinator and pilot (LSE) administrator

* LSE role have SC/pilot administrator collect

meter data and perform

baseline calculation for non-aggregated customers

* CAISO role none

How will performance be measured?

As in PG&E’s XSP, performance would be measured by subtracting the baseline load from the event load. A 10-in-10 wholesale baseline methodology would be used to determine the baseline load and estimate the average load from the 10 similar days to get the baseline load.

What are the expected challenges?

The primary challenge is whether the negative energy wholesale market price would suffice to incent the increase in consumption, due to the impacts on the retail maximum demand charge. The main impediment is the non-coincident facilities related demand charge, which for transmission is set by the Federal Energy Regulatory Commission, and passed through by the CPUC. For E-20T customers, PG&E’s maximum demand charge is $8.01/kW.

Additional challenges include parsing and including the Power Charge Indifference Adjustment; how the retail rate signals from current time-of-use periods and the to-be implemented time-of-use periods will align, and how the pilot would be funded.

What are potential solutions?

Sufficiently negative energy prices could overcome or help mitigate the maximum demand charge.

Flexibility around the CPUC-jurisdictional, generation-related coincident demand charge could also help. Consideration could be given to seeking FERC approval of a different calculation of cost basis and rate design for the maximum demand charge, as the transmission system is summer peaking and it would be highly unlikely that shoulder-month Critical Consumption Periods would lead to increased marginal transmission costs; this different calculation of cost basis and rate design could be time-limited and subject to subsequent review.

For the funding challenge, utilities could seek approval for fund-shifting, or this proposal could be worked into the XSP Pilot for PG&E; a cap on the number of participants, or limiting the participants to large power rate schedules could help address funding constraints.

Product Evaluation

The goal of this section is to elaborate on the characteristics of the product and its expected implementation for a set of evaluation criteria that can aid judgement on the merits / value.

**Market integration**

*Describe how this product is linked with the CAISO energy market.*

Is it intended to be directly dispatchable by CAISO? no

If yes, does it fit into an existing market model? n/a

What changes to policy or practice are required? n/a

Is the product dispatched outside of the CAISO market, but reasonably considered “market integrated?”

Yes; the customer’s response is directly linked to the CAISO market price, so this could be considered to be market integrated, as the response is triggered by the market price signal.

**Grid needs match**

What grid needs does this product solve? It avoids renewable curtailment. To maintain

a balanced system any increase in load has to be met with increased generation.  If curtailment is happening, then any increase in load should likely also reduce renewable curtailment.   While this issue is complex, it is hoped that if this consumption product is called after the day-ahead market run and LSE notifies the CAISO, then if the CAISO could incorporate the information into their real-time load forecast that would inform the real-time unit commitment and dispatch models.   Since load would be higher than the day-ahead forecast, then there should be less renewable curtailment.  The role of the CAISO is important as the load is not bid into the CAISO’s real-time market.  (Load is only bid in day-ahead.)  Moreover, the CAISO real-time market is continually learning, and adjusting its forecasts in real time; thus, when there is more or less load than forecast in an interval, the load-supply balance is re-balanced in a subsequent interval. Accordingly, while the critical consumption does not get a market award, it is possible for it to influence the real-time market.

Does this product enable the resource to also provide other services (i.e., dual participation)? What additional services does it enable?

It should enable dual participation by customers.

How do the dispatch details (described previously in *product description section*) inform its value to the grid? For example, describe the response time, notification, geographic granularity, etc. and how this supports grid needs?

By being triggered on a day-ahead timeframe during expected periods of renewables curtailment based on Day-Ahead prices and at the granular nodal level, the product can support the grid need to avoid renewable curtailment.

For each of the grid needs identified in the list above, describe:

How can the magnitude of value be estimated?

Currently, the negative market price; in the future, there might be a way to access the value provided by avoiding renewables curtailment, but that doesn’t exist yet.

* Is there an existing revenue mechanism accessible?
* Yes, for the negative market price of energy.

What Is the minimum kW / kWh size? 100 kW

What is the maximum kW / kWh size? n/a

Is the product delivering an incremental service?

Yes, by avoiding renewable curtailment.

How is the incremental value determined?

No methodology currently beyond negative wholesale energy market price

**Customer Experience**

* ***THE PILOT MUST ALLOW DUAL PARTICIPATION WITH BIP***
  + **No need for capacity value payment *if* can dual participate with BIP (capacity program) and pilot (energy program)**

What is the anticipated ability of customers to respond to the product in the time frame and geographical time space suggested?

It depends on the economic incentive.

Are there particular customer co-benefits related to participating?

Dual participation should increase the RDRR headroom under the cap, because the load that participates in an economic (energy) program while also participating in a reliability (capacity) program does not count towards the RDRR cap; accessing lower energy costs, should enables increased in-state energy-intensive manufacturing, which helps the state meet its climate goals by avoiding leakage.

What are the likely use cases where participant economic benefit coincides with grid needs (e.g. scheduling an extra production shift during low price periods)?

Likely use cases are where participant economic benefit coincides with grid needs: increased manufacturing production during low price periods

What are the challenges and opportunities for participation across customer classes (residential, small commercial, large commercial, industrial, agriculture, municipal, etc.)?

CLECA suggests limiting this to large power customers: PG&E E-19T, E-20T; SCE TOU-8-Sub as they have the meter data granularity and this would avoid issues with distribution demand charges.

Can current DR-providing customers participate without significant control technology upgrades?

Yes, large C&I customers could.

**Grid IT systems**

*Describe how the product is compatible with existing utility IT/metering/billing systems.*

Does retail meter data granularity meet product needs? for large C&I, yes

Do overall utility IT systems meet product needs?

Not yet; expect a “work-around” (like PG&E’s use of Olivine for XSP)

If no to any above, what changes may be warranted?

Utility billing system changes to enable real-time pricing; for this proposal, payment would be made to the customer outside the utility billing system.

What are potential challenges/costs of those changes?

Utility billing system changes are significant

What are potential spillover benefits of those changes?

More dynamic and responsive load generally

**Greenhouse Gas**

What are the expected greenhouse gas emissions impacts from implementing the product?

This is difficult to estimate and is subject to many factors and assumptions. On the generation side since less renewables are curtailed, there should be no increased generation emissions. On the customer side, it is possible that there may be additional emissions from the manufacturing process. However, if load is shifted from a time period when gas is on the margin to period when renewable is on the margin, then the overall emissions would be reduced.

Grid Needs and DR Shift Opportunities

This document presents a framework for connecting “needs” of the power system with demand response (DR) and broader DER services and technology. In the first column, there are high-level grid policy drivers described, and then the values, mechanisms, and revenue opportunities (if applicable) for supporting these needs with responsive demand-side technology.

The core needs expressed here are to provide **low cost** service, with **low pollution**, **high reliability**, and **equality** in service.

Note: This version of the table builds on the original presentation of a “grid needs matrix” from the April 19, 2018 meeting of the Load Shift Working Group. It incorporates comments from that meeting, and subsequent comments.

| **Grid Policy Need** | **Value** | **Market Mechanism** | **Revenue for Shift DR** | **Operational Requirements**  **[see notes below for selected details]** | **Good fit for Shift?** | **Notes** |
| --- | --- | --- | --- | --- | --- | --- |
| **Low cost** **dispatch** (with low pollution) | Fuel and other **marginal cost operational savings** while balancing dispatchable generation with net load | Day-ahead Energy | Energy market price arbitrage | CAISO’s ESDER 3 proposes load shift resource through PDR**. [see note below on PDR for Shift]**  OR  Real-time dynamic prices + responsive load controls. | ***yes*** | Market prices should reflect opportunity for reduced operating/ marginal costs  Value includes providing additional economic response to oversupply conditions avoiding uneconomic non-renewable curtailment |
| Real-time Energy | Energy market price arbitrage | Same as above. | ***yes*** | Same as above |
| **Renewable generation capacity that is built for RPS compliance** | RPS Compliance Credit | *Who gets the value from a salvaged RPS credit when curtailment is avoided?* | Not established | ***yes*** | Value includes providing additional economic response to oversupply conditions avoiding uneconomic renewable curtailment.  Pay for avoided RPS losses based on avoided LCOE for new renewables? |
|  | Frequency Regulation | Ancillary services | Ancillary services payments | Regulation Services not available through PDR or ESDER3 proposed PDR. Reg Up/Down is through NGR **[see note on NGR Regulation Service]** |  |  |
|  | Voltage support | Distribution system voltage regulating and VAR equipment investment. | Not expected | Not established |  | Rule 21 Interconnected solar and storage could provide this. |
| **Low Pollution**  (at low cost) | GHG Emission Reductions | ?  Value of GHG reductions that is not reflected in RPS compliance credit. | ? | Not established | ***yes*** |  |
| Local air quality improvements;  Environmental Justice | Cost of compliance with air quality regulations reflected in market bids.  *Equality in exposure is not reflected.* | Energy market price arbitrage | Partially incorporated into bid price (i.e., no GHG adder) | ***yes*** | Overlap with energy market price |
| **High Reliability Installed System** | **Serve the peak generation capacity need** | Resource Adequacy (system, local) | Capacity payments | For curtailment today: Minimum response 4 hours/day for 3 consecutive days and 24 hours/month |  | No forward capacity procurement market mechanism, so we have capacity markets.  e.g., Demand Response Auction Mechanism pilot, bi-lateral procurement contracts. |
| Serve the **ramp** (up/down) | Flex RA | Capacity payments | Participation requirements under PDR  Flexible capacity resources submit economic bids in DA and RT markets to meet Must Offer Obligation. Based on ability to meet technology agnostic flexible capacity categories |  | Note this market mechanism is evolving, with detailed categories including:  Category 1 (Base Flexibility), Category 2 (Peak Flexibility), Category 3 (Super-Peak Flexibility). |
| **Transmission** **capacity** investments delayed, reduced cost, or deferred. | ? | ? | Not established, other than requirements set forth by individual solicitations. |  | Forthcoming CAISO Product = alternative market mechanism? |
| Transmission Alternatives | Storage as Transmission Asset | ? | **[see note on Transmission Alternatives]** |  | Pending CAISO Stakeholder process. **The scope of this initiative is to enable storage providing cost-based transmission services to also participate in ISO markets and receive market revenues to provide ratepayer benefits and provide greater flexibility to the grid.** |
| **Distribution capacity** investments delayed, reduced cost, or deferred. | Distribution Service Market product (e.g., distribution capacity) | Distribution Capacity Payment | Not established, other than requirements set forth by individual solicitations. |  | Per DR Scope, recognize need, but don’t design product to conform to that need? |
| **Equal service access** | Equity in the reliability and availability of basic electricity services for residential and light commercial buildings. | Participation in, and benefits from participating in the markets above. | Through the mechanisms above. | Same as above |  | Policy design could incorporate visibility into customer participation and benefits. |

**Notes on Operational Requirements:**

**[PDR for Shift]**

CAISO’s ESDER 3 proposes load shift capabilities under the demand response provider agreement as a PDR. The PDR load shift resource would be required to have two separate resources reflecting and bidding its capability to curtail and consume as distinct resources, but this does not require certain bidding behavior. For example, a resource could only bid consumption. The resource would be required to begin their bidding at a minimum of zero bid price for curtailment and at a negative price for consumption. The list below describes other key aspects of the concept:

* A typical use value (curtailment/consumption) adjustment of its Metered Generation Output quantity would be required to determine a resources performance (Demand Response Energy Measurement DREM).
* Settlement of performance would be at the Locational Marginal price.
* PDR load shift consumption can provide RT energy (15 minute or 5 minute). Only PDR load shift curtailment can provide either DA or RT energy and capacity could qualify for Ancillary Services (Spin and Non-Spin)
* PDR load shift resource could qualify for System and Local RA for curtailment capacity. Consumption capability may qualify for Flex (TBD) RA.
* Resource would incur full retail load charges for provision of consumption services.
* Telemetry required for resources >= 10 MW
* Aggregations limited to one Sub Lap
* Registration of underlying load service accounts required

**[Transmission Alternatives]**

Currently in development. The idea is market-based revenues generated from market-based services can reduce the costs of the asset recovered under a cost-of-service contract, reducing the burden on rate-paying consumers. A new agreement will identify the terms and conditions that apply to market participation and the treatment of market participation revenues.

Requirements in development:

1) The contractual relationship with the SATA resource and the ISO,

2) The determination of how a SATA resource may access market revenues, and

3) The cost recovery mechanism.

**[NGR Regulation Service]**

Reg Up/Down qualified under NGR model for both Energy Storage and dispatchable demand response

* Requires automated generator control (AGC)
* Provision of response in 4 seconds
* 24x7 participation
* 0.5 MW size requirement
* Aggregations limited to one point of interconnection.

1. <https://www.eia.gov/todayinenergy/detail.php?id=30692>; *see also* <https://www.utilitydive.com/news/california-solar-spike-leads-to-negative-caiso-real-time-prices-in-march/440114/>; *see also* <https://ei.haas.berkeley.edu/research/papers/WP292.pdf> [↑](#footnote-ref-1)
2. <http://www.caiso.com/Documents/CurtailmentFastFacts.pdf>; Comments of the California Independent System Operator Corporation, filed Oct. 10, 2018, in R. 16-02-007, at 9. [↑](#footnote-ref-2)
3. <http://www.caiso.com/Documents/Wind_SolarReal-TimeDispatchCurtailmentReportOct08_2018.pdf>   [↑](#footnote-ref-3)
4. The CAISO’s DA market run results are supposed to be announced by 2 pm, but they can occur later in the afternoon. [↑](#footnote-ref-4)